State of California

AIR RESOURCES BOARD

Proposed Guidelines for the Control of Emissions from Coal-Fired Power Plants

Prepared by:

Stationary Source Control Division

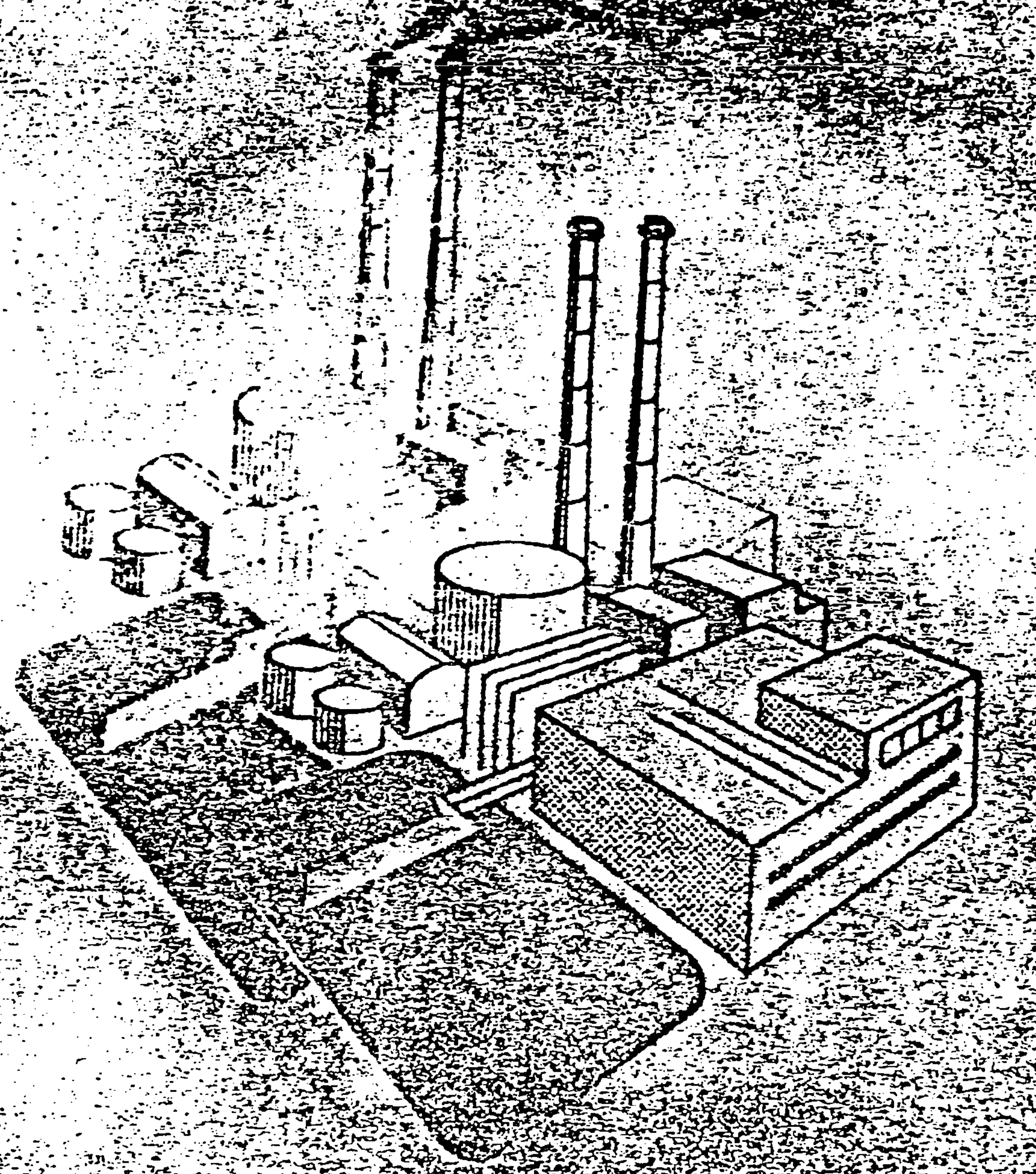
and

Regional Programs Division

Presented to the Air Resources Board for Discussion on

June 24, 1981

FOR THE CONTROL OF EMISSIONS FROM COAL-FIRED POWER PLANTS



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Public Meeting to Discuss Proposed Guidelines
for the Control of Emissions
from Coal-Fired Power Plants

Scheduled for Consideration: June 24, 1981
Agenda Item No.:

SUMMARY

Two California utilities, Southern California Edison and Pacific Gas and Electric, have proposed coal-fired power plants for construction in California. Before such facilities can be built, they must meet air quality requirements. In California, these requirements include those established by the Environmental Protection Agency (EPA), the Air Resources Board (ARB), and the local air pollution control districts (APCDs).

Current EPA standards for coal-fired power plants are specified in the New Source Performance Standards (NSPS) applicable to such plants. These standards represent minimum control requirements and are applicable nation-wide. The staff has reviewed these standards as well as the actual permit conditions set by EPA and believes they do not usually represent the best available control technology.

Local districts' new source review rules require the application of the best available air pollution control technplogy on new major sources. In reviewing the applications for coal-fired power plants, the district in which the facility is being proposed must, therefore, make a determination of what is the best available technology. In order to assist these agencies

in the review process and to ensure consistent requirements, the staff has developed proposed minimum guidelines for controlling emissions of sulfur dioxide, oxides of nitrogen, and particulate matter from new coal-fired power plants. These guidelines are being proposed as minimum guidelines; more stringent requirements may be considered by the local APCDs on a case-by-case basis.

In developing these guidelines, the staff has reviewed the work of EPA and other research organizations, observed similar facilities in Japan, and conducted a workshop with the utilities, manufacturers, and other state and local agencies.

The proposed minimum guidelines are: a 95 percent reduction of sulfur dioxide (SO_2) when the inlet concentration to the SO_2 control device exceeds 300 ppm, and a proportionately lower percent reduction resulting in an outlet concentration not to exceed 15 ppm when the inlet concentration to the SO_2 control device is equal to or less than 300 ppm; 0.005 grains per actual cubic foot (gr/ACF) for particulate matter; and 0.45 pound per million (lb/mm) Btu of heat input for oxides of nitrogen (NO_x) below 50 percent of rated capacity, and 0.09 lb/mm BTU of heat input at 50 percent, and greater, of rated capacity. Guidelines for compliance determination and emission monitoring are also specified.

Control technologies needed to achieve the proposed guideline levels are readily available today. These include combustion modifications and ammonia-based flue gas treatment for NO_x, flue gas desulfurization for SO_2 and a baghouse for particulate matter.

The capital cost of installing the control equipment necessary to achieve the proposed emission levels ranges from $42 to $66/kw for NO_x controls (in addition to combustion modifications), approximately $34/kw for particulate matter controls, and $96 to $179/kw for SO_2 controls. Based on a total coal-fired power plant capital cost of $1175 to $1357/kw, the control equipment accounts for 15 to 21 percent of the total capital cost.

The levelized cost of installing the control equipment necessary to achieve the proposed emission levels ranges from 4.4 to 6.5 mills/kwh for NO_x controls (in addition to combustion modifications), 1.0 to 2.0 mills/kwh for particulate matter controls, and 6.7 to 12.4 mills/kwh for SO_2 controls. The sum of the control equipment levelized costs should represent somewhat less than 15 to 21 percent of the total plant levelized cost.

The staff has not identified any significant adverse environmental or other impacts that would result from installation of control equipment to meet the emission limits recommended by these guidelines.

deep reduction target in combination with combustion modifications. According to Exxon, the result of that study is based on the use of older technology, and recent advances in the DeNOx technology would result in an increase in DeNOx performance of 10 to 20 percent over the previous performance predictions.

This technology has not been demonstrated on a full-scale coal-fired boiler. There is concern that the fly ash from coal firing may deposit on interior grids, change gas flow patterns and temperature profiles, and foul or erode injection nozzles.

Thermal DeNOx results in the emission of unreacted ammonia from the stack, known as ammonia slip. Ammonia slip is estimated to be about 50 ppm at an ammonia to NOx mole ratio of 1.5:1. Also, ammonia reacts with sulfur trioxide in the flue gas to form ammonium bisulfate, which partially precipitates in the air preheater, and necessitates occasional plant shutdowns (perhaps every six months) for air preheater washing. Furthermore, Thermal DeNOx in utility boilers is generally only effective at high unit loads, with the efficiency of NO reduction falling off sharply with load.

[redacted]

The Selective Catalytic Reduction Process (SCR) is a commercial process for reducing NOx emissions in a flue gas stream. No other commercially available NOx reduction method can achieve the high reductions in NOx that can be achieved by SCR with such certainty and reliability. Its effectiveness is evidenced by its widespread use on oil-and-gas-fired, large and small units in Japan. The latest estimates indicate that there are approximately 100 commercial installations that use the SCR process to reduce NOx emissions from gas-and-oil-fired facilities (Ando, October 1980).

After successful application on oil and gas units to achieve 80-90 percent NOx emissions reductions, this process has been applied to reduce NOx emissions from coal-fired utility boilers in Japan. At the early stage of development for coal-fired units, the SCR process encountered several technical and operational problems. However, most of the problems have been solved, as demonstrated by extensive pilot scale testing (Itoh, et al., 1980; Wiener, et al., 1980; Narita, et al, 1980; Aoki, et al., 1980; Sengoku, et al., 1980; Levers, et al, 1980; Nakabayashi, et al, 1980) as well as commercial scale applications. These commercial scale applications are discussed in detail later in this section. In addition, SCR has been planned for many large coal-fired utility boilers in Japan (Table VII-5).

Published papers have identified major concerns regarding operational and technical aspects of using a selective catalytic reduction system on a coal-fired utility boiler. On the other hand, several papers indicate that many of these concerns have been resolved and provide data and other relevant information gathered at the pilot scale and commercial scale application of the SCR system.

(i) Concerns Regarding the Use of SCR

The major concerns regarding the operational and technical aspects of using an SCR system can be separated into two categories. The first, catalyst related, deals with catalyst life, catalyst activity, catalyst erosion, catalyst blinding, catalyst resistance to contaminants in the flue gas, and the catalyst as a promoter of SO_2 to SO_3

Table VII-5

Planned SCR Installations Coal-Fired Units in Japan

Power Company	Station & Unit	Capacity Treated with SCR, MW	Planned Completion
Electric Power Development Company	Takehara 1[1]	250	July 1981
	Takehara 3[1]	700	1983
	Matsuura 1[1]	1000	Unavailable
	2[1]	1000	Unavailable
Chugoku Electric Power Company	Shin-ube 1[2]	75	Sept. 1982
	Shin-ube 2[2]	75	Sept. 1982
	Shin-ube 3[2]	156	Aug. 1982
Joban Joint Power Company	Nakoso 8[2]	600	Dec. 1982
	Nakoso 9[2]	600	Apr. 1983

1/ Source: Electric Power Development Company, April 1981

2/ Source: "Measures for NOx Abatement of Thermal Power Stations in Japan", Ministry of International Trade and Industry, April 1981 oxidation. The second category, related to ammonia, includes ammonia control, ammonia carryover, and NH_3/SO_3 byproduct formation and its deposition on air preheaters.

a. Catalyst Related Concerns

The major concerns that have been identified relate to catalyst life, activity, erosion, and blinding effect. Most of the catalysts that have recently and are now being developed are based on titanium dioxide (TiO_2) with vanadium pentoxide as the active component. When these catalysts were introduced for oil firing, the manufacturers issued catalyst life guarantees of one year. Experience has shown that commercial installations using grid catalysts for oil firing have operated for two years without problems and without replacement of the original catalyst. As of April 1981, none of the commercial SCR units have required a catalyst change. In the meantime, the life-time guarantees for oil firing have been extended to two years and the actual lifetime is expected to be even longer. That illustrates the performance and life of catalysts for oil-fired applications.

Although only two coal-fired utility applications have been in operation, those applications are achieving the design removal efficiencies without any difficulty. Catalyst life from three to five years is expected.

One of the concerns that has been frequently expressed relates to catalyst erosion attributed to fly ash. The catalyst that are being developed for coal-fired applications are shaped like a honeycomb, plate or pipe. The catalyst shape can be produced as a ceramic or metal substrate coated with the catalyst material or as a homogeneous form composed of purely catalyst material. The homogeneous catalyst shape is softer and can be eroded by the fly ash; however, the newly exposed catalyst is still catalytically active, and thus continues to perform. At the Shimonoseki power plant application, a "dummy" spacer (that is, a honeycomb section but with no active catalyst material in it) with the same shape as that of the catalyst was placed on top of the first catalyst layer, to maintain a uniform parallel gas flow and to prevent catalyst erosion by fly ash. Examination of the catalyst below the dummy layer shows no detectable erosion of the catalyst. The smooth operation of the SCR shows that this procedure apparently resolves the problem. In addition, several process vendors have demonstrated catalyst resistance to erosion of high grain loading flue gases.

Catalyst blinding by dust (fly ash) is another concern that has been expressed in the published papers. For an SCR system for coal-fired applications, two separate equipment arrangements can be used. One is called a "low dust" SCR system, in which the boiler flue gas is first passed through a hot-side electrostatic precipitator, and the cleaned flue gas flows through the catalyst. The other arrangement is called a "high dust" SCR system, in which the boiler flue gas flows through the catalyst without prior cleaning and the flue gas then flows through gas cleaning equipment after the catalyst reactor. Both the "low dust" and the "high dust" SCR systems have their advantages and disadvantages, which will be discussed in Chapter X. Here, the discussion is limited to how these two systems influence catalyst blinding.

Tests have shown that in the case of the "low dust" system, although the dust content in the gas is small, the dust consists of fine particles relatively rich in alkaline components and it tends to stick on the catalyst surface, particularly at the inlet face. This deposit of fine dust at the catalyst surface may cause blinding of the catalyst. This problem does not occur with the "high dust" system because the full ash load has a sandblasting effect which cleans the catalyst surface. Recent tests in Japan at the Nakoso plant, Joban Joint Power Co., and the demonstration at Shimonoseki plant of Chugoku Electric Power Company support the above conclusion (Ando, October 1980).

In addition to the blinding of the catalyst by dust, it is possible that the catalyst could be blinded by residual oil mist carry-over. Manufacturers of catalyst systems in Japan reported to the NOx study team that forced carry-over of residual oil mist in pilot plant tests resulted in blinding of the catalyst, rendering the catalyst ineffective. Since residual oil might be used in coal-fired power plants during start-up, such a problem is of concern. The Japanese manufacturers reported that blinding by oil mist carry-over has not occurred in any of the demonstration or commercial installations in Japan. Tests by manufacturers have shown that the residual oil coating of the catalyst cannot be removed by raising the temperature of the catalyst, although diesel oil coating can be removed, and avoided in operation, by raising the temperature of the catalyst to 350^{o} Centigrade (662^{o}F). It is possible that the residual oil mist coating could be removed if the catalyst were removed from the reactor and taken to a cleaning site. It is also possible that a by-pass of the reactor could be constructed, so that the reactor could be by-passed during start-ups or upset conditions which could result in an oil mist carry-over. However, it is obvious that steps can and should be taken in the operation of the power plant to avoid the possibility of residual oil mist carry-over.

Catalyst ability to resist all contaminants in the flue gas is another concern that has been expressed. However, pilot plant and commercial operation have shown that the catalyst can resist flue gas contaminants. For example, in one instance, the catalyst was operated successfully for over 9,000 hours continuously at a pilot scale coal-fired facility, and catalysts also have been in operation at two commercial coal-fired utility boilers. Contaminants in the flue gas have not affected the catalyst performance up to April 1981 in those installations.

The oxidation of sulfur dioxide (SO_2) to sulfur trioxide (SO_3) is increased by the catalyst. The catalysts that are now in use are composed mainly to titanium dioxide (TiO_2) with a small amount of vanadium pentoxide (V_2O_5). The V_2O_5 oxidizes SO_2 to SO_3. Sulfur trioxide can then react with ammonia (NH_3) and lead to the formation of ammonium compounds that may deposit on the air preheater and may also cause other environmental problems. To help correct this problem, new catalysts have been developed that suppress the oxidation of SO_2 to SO_3. Whereas the conventional catalyst could oxidize 2 to 4 percent of the SO_2 to SO_3, new catalysts have been developed that suppress the SO_2 to SO_3 oxidation to less than 0.5 percent. Figure VII-6 shows the performance of a catalyst designed to suppress SO_2 to SO_3 oxidation.

In summary, most of the concerns regarding the use of a catalyst for coal-fired boilers have been resolved. The blinding of the catalyst by oil mist carry-over has never occurred in commercial operation, and simple design techniques can preclude the possibility of blinding. Furthermore, the SCR systems at the two commercial scale coal-fired utility boilers have been operating smoothly without any problems. In fact, although the catalyst manufacturers guarantee the life of the catalyst for one year, they expect the catalyst to last for over two years (Ando, October, 1980; Nakabayashi, 1980).

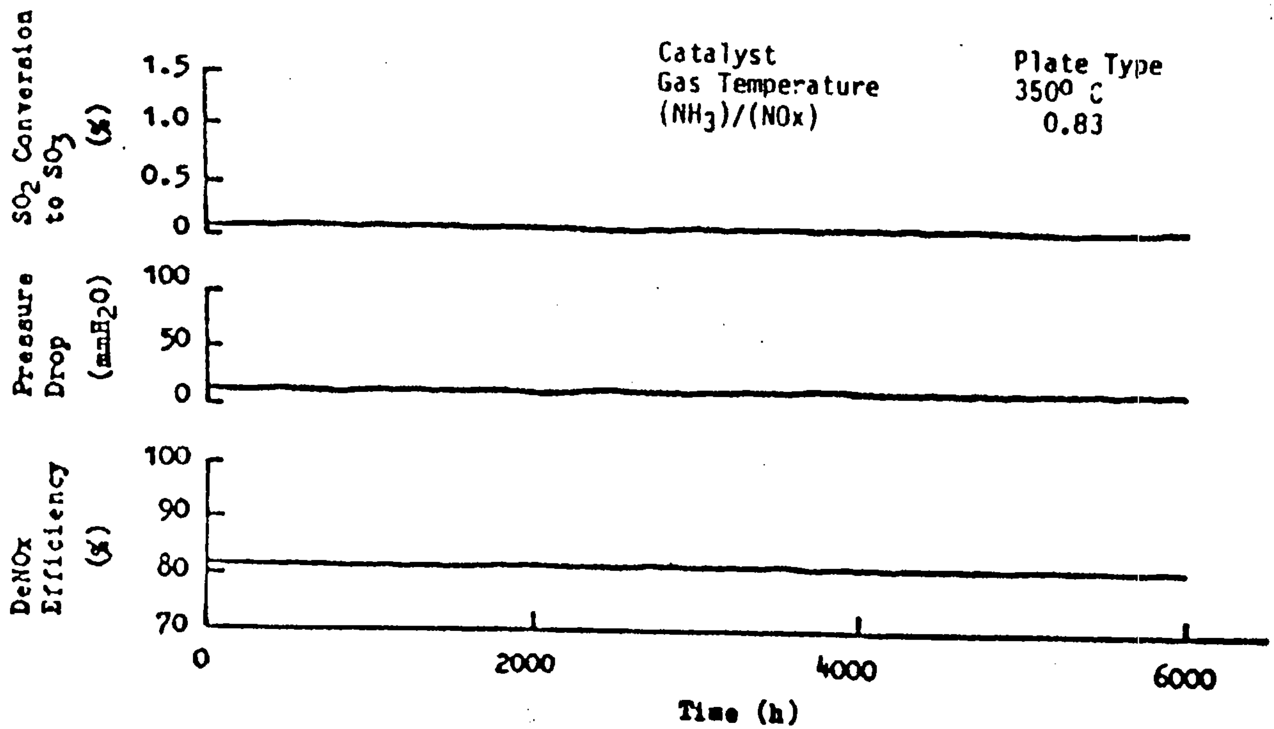
b. Ammonia Related Concerns

Concerns other than those related to catalysts are ammonia control and air preheater plugging by ammonium bisulfate deposition. The specific concerns are ammonia breakthrough; availability and reliability of instruments to monitor ammonia breakthrough; and air preheater plugging.

Ammonia injection in an SCR system employs a feed forward control based on a product of boiler load and reactor inlet NOx concentrations, and fine tuning supplied by feedback of the reactor outlet NOx concentration (Mobley, 1980; Jones, 1981). A small part of the injected ammonia does not react with NO and is carried out with the flue gas. This is known as slip or breakthrough. Many prefectures in Japan require utilities to limit ammonia slip to less than 10 ppm and this has resulted in the utilities requiring the SCR manu-

Figure VII-6

Pilot Plant Test of a Parallel Flow Reactor Treating
Flue Gas from a Coal-Fired Utility Boiler



Source: T. Narita, et. al., "Babcock-Hitachi NOx Removal Process for Flue Gases from Coal-Fired Boilers" Proceedings of the Joint Symposium on Stationary Combustion NOx Control, Vol. II, (October, 1980).

heater is restricted, and eventually the boiler must be shut down so that the air preheater can be washed. The accumulation is much more rapid in low dust systems than in high dust sytems because in high dust systems the dust removes the deposits.

If the air preheater is modified so that the intermediate and cold section elements are made into a continuous element, the deposition is minimized since there are not element ends for bulbs of deposits to form. Also, use of increased steam pressure and temperature with a round nozzle soot blower (rather than flare nozzle) at more frequent intervals reduces deposits. Finally, raising the air preheater temperature for a short period of time to above 300° C causes the ammonium bisulfate to evaporate. Adherence to these procedures, Gladelius and EPDC officials report, will eliminate the necessity for air preheater washing at times other than normal boiler outages for maintenance.

Operators of the Shimonoseki power plant (high dust system) and the Tomato Atsuma power plant (low dust system) reported to the NOx study team in April 1981 that air preheater plugging had not occurred.

In conclusion, it is the staff's belief that SCR is a commercially available technology for coal-fired boilers.

(ii) Commercial SCR Units on Coal-Fired Utility Boilers in Japan

a. Units in Operation

1. Shimonoseki Station Unit #1, Chugoku Electric Power Company

One of the SCR systems in operation viewed by the NOx study team was installed as a retrofit on a 175 MW coal-fired boiler, Unit #1 at the Shimonoseki Station of the Chugoku Electric Power Company. Unit 1 commenced operation in 1967 on coal and was switched to oil in 1970. In May, 1980, the unit was switched back to coal. In order to switch to coal, the utility had to reduce its overall NOx emissions to less than 350 ppm, averaged over an hourly basis. The utility decided to install an SCR system designed for 60 percent reduction to comply with the NOx emission limit. The details of the design basis of the SCR system are shown in Table VII-6. A picture of the reactor is shown in Figure VII-9.

The boiler #1 is a base load unit with a flue gas temperature at the reactor of from 350 to 370°C at full load. The unit is occasionally operated at 25 percent load, which results in a drop in the reactor flue gas temperature to below 300°C. To raise the temperature of the flue gas through the catalyst at 50 percent load, an economizer bypass system is installed to maintain the flue gas at the desired temperature.

Flow of flue gas through the reactor is downward to prevent plugging and the reactor is equipped with soot blowers (the soot blowers have not been used). High dust laden flue gas is taken from the economizer outlet and directed to the top inlet of the reactor and returned to the inlet of the air preheater. A "dummy" catalyst layer is located upstream of the five lower catalyst layers to prevent catalyst erosion by the fly ash and guide the flue gases through the reactor. A picture of the type of catalyst used in the reactor is shown in Figure VII-10.

To comply with the current regulation, a NH_3/NOx mole ratio of 0.51 is used, which reduced the NOx emission level by 50% from 500 ppm to 250 ppm. The observed ammonia slip and control efficiencies are shown previously in Figure (VII-7). Enough room has been provided in the reactor for the addition of sufficient catalyst to provide a long-term NOx reduction of 80%. The air preheater had an existing soot blower system on the cold side and was modified by adding a soot blower on the hot side and by altering the intermediate temperature elements. The hot side sootblower is now operated four times a day and the cold side sootblower is operated twice a day. Plugging of the air preheater by ammonium bisulfate has not occurred.

Plant operators are well satisfied with the SCR system. They expect catalyst life to be more than three years.

2. Tomato-Atsuma Plant, Hokaido Electric Power Company

The NOx study team also visited a new 350 MW coal-fired boiler at the Tomato Atsuma Power Plant of the Hokaido Electric Power Company. The local government required the NOx emissions from the new unit to be reduced below 200 Nm^3/hr (170 ppm at 6% O_2, average). The overall NOx level is reduced to below 200 ppm by using combustion modifications including staged combustion, flue gas recirculation, and low NOx burners. In order to further reduce the overall mass emissions, one-fourth of the flue gas is treated through an SCR system designed for 80 percent NOx removal.

The plant burns a low-sulfur coal (0.3% S). A hot-side electrostatic precipitator is used to reduce the dust content to approximately 45 mg/Nm^3. One fourth of the flue gas exiting from the hot ESP is directed to the SCR reactor. An economizer bypass system has been installed to maintain the flue gas in the reactor at the desired temperature at low loads.

The unit, with SCR, was started on July 15, 1980. By March 31, 1981 it had 5,270 operating hours. NOx removal efficiency of the SCR system is 83% with ammonia slip of 2 ppm.

The SCR is not operated below 50% load. No problem has been encountered with air preheater plugging. However, the probability of air preheater plugging is reduced because the flue gas exiting from the SCR is diluted by re-entering the duct containing the remaining three quarters of total flue gas flow. Soot blowers are operated on the air preheater three times per day. Soot blowers have been installed in the reactor but have not been used.

b. Planned Units

The Japanese have plans to use the SCR system on a number of additional coal-fired units in the future. Some of these units are already under construction. As previously presented, Table VII-5 shows the details and the scheduled completion year. The planned use of SCR underlines the confidence of the Japanese in the SCR technology and its application to coal-fired utility boilers.

(iii) Commercial Availability in the U.S.

The SCR system is commercially available in the U.S. for large coal-fired applications. The ARB staff, in December 1979, contacted a number of SCR process vendors to assess the availability of their control system for PG&E's Fossil 1 and 2 coal-fired power plants then scheduled to start operation in 1986. Several process vendors reported that they were prepared to offer their system with commercial guarantees (see Appendix B). One of those process vendors is Kawasaki Heavy Industries (KHI) which has sold an SCR unit for a coal-fired power plant in Japan. Another process vendor, IHI, is offering SCR units for coal application, and has also sold an SCR unit for a 600 MW coal-fired power plant in Japan.

(iv) Efficiency of NOx Reduction Using SCR

The SCR process is capable of achieving up to 90 percent control. However, while most of the industrial boilers operating in Japan are designed for NOx control in the 90 percent range, utility boiler applications commonly are designed for 80 percent control because, for a stipulated allowable ammonia slip, 80 percent NOx control requires less catalyst volume than 90 percent control. For an SCR system, if maximum ammonia slip is to be maintained at less than 5 ppm, to increase the NO_x removal efficiency from 80 to 90 percent would require a 35-50 percent increase in catalyst volume (Nakabayashi, et al., 1980). Since reactor and catalyst costs can contribute as much as 30 to 40 percent of the total SCR system capital cost, the overall capital cost can be reduced by approximately 10 to 15 percent because of this reduced requirement for catalyst alone. Also, there is an expected reduction in operating cost because the catalyst will eventually have to be replaced. Ammonia and energy consumption are also reduced for 80 percent control.

Figure VII-11 shows efficiency as a function of NH_3/NOx mole ratio. According to this figure, about 10 percent less ammonia would be required for 80 percent NOx control as compared to 90 percent NOx control. The actual reduction in ammonia usage by individual units may vary slightly depending upon the design and other operating variables of the SCR system. By reducing ammonia usage to 80 percent, ammonia slip also may be reduced as shown on Figure VII-11. The reduced ammonia slip, in turn, is expected to result in reduced potential for ammonium bisulfate precipitation on the air preheater. Reduced consumption of ammonia will probably result in a reduction in the requirement for carrier gas such as steam or air, and a smaller ammonia tank and vaporizer.

A Japanese consultant estimated the cost for installing an SCR system on a new coal-fired 700 MW utility boiler, operating at a 70 percent capacity factor. The consultant estimated that cost for both 80 and 90 percent control efficiency, for a high dust system and maintaining an ammonia breakthrough of between 5-10 ppm, and concluded that the total annualized cost for an SCR system operating at 80 percent efficiency would be about 30 percent less than for 90 percent control efficiency (Ando, October 1980).

From the above considerations, the staff concludes that an 80 percent reduction is the appropriate limit for using an SCR system for a coal-fired utility boiler.

3. Conclusion

Based on the above disucssion in this chapter, it can be concluded that NOx emission levels of 0.35 lbs per million Btu to 0.45 lbs per million Btu can be achieved by using combustion modification techniques. This, coupled with a flue gas treatment system, designed for 80 percent emission reduction, would result in NOx emission levels of 0.07 lb per million Btu to 0.09 lb per million Btu. The ARB staff believes that the technologies to achieve this range are currently available. The ARB staff recommends that a NOx emission level of 0.09 lb per million Btu should be selected as a final emission control level. This will ensure that the utility has operational flexibility, and it will also allow, whenever possible, the utility to operate the SCR system at less than 80 percent control efficiency. The staff believes that the level of 0.09 lb per million Btu should apply between 50 percent and 100 percent of full load, and a level of 0.45 lb per million Btu, as a minimum, should apply below 50 percent load.

[redacted]

In this section, the cost of the control technology to achieve the proposed level of control is discussed. The proposed level of control can be reached by using a combination of combustion modification techniques and an SCR system. The cost for combustion modification and for the SCR system are discussed below.

1. Cost of Combustion Modifications

The staff proposes that a level of 0.45 lbs per million Btu can be achieved by using combustion modification techniques. Based on discussion with boiler manufacturers and other consultants, the staff believes that it is very difficult to estimate the incremental cost of NOx controls for a utility boiler without evaluating the boiler design, type of fuel to be burned, and other site specific information.